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A Synopsis prepared for the opening
meeting of the Department of the Interior
OIL SHALE ADVISORY BOARD

THE
OIL SHALE
POLICY PROBLEM

JULY 7, 1964

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UNITED STATES DEPARTMENT OF THE INTERIOR
Stewart L. Udall, Secretary

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UNITED STATES DEPARTMENT OF THE INTERIOR

THE OIL SHALE POLICY PROBLEM

A synopsis prepared for the opening meeting of
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Oil Shale Advisory Board
July 7, 1964

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THE OIL SHALE POLICY PROBLEM

A synopsis prepared for the opening meeting of the
Department of the Interior Oil Shale Advisory Board,
July 7, 1964

Introduction

Oil shale deposits were included among the leasable minerals covered by the Minerals Leasing Act of 1920. Federally-owned deposits were withdrawn from leasing and disposal by Executive Order in 1930, however, and none have ever been exploited. In recent years, technologic advances have apparently brought oil shales within economic reach and there is currently much interest in opening Federal lands for development.

The enormity of the Rocky Mountain deposits, their concentration in a relatively small area, and other characteristics pose a wide variety of special economic, legal, and conservation problems, and make difficult the policy questions of when and how to develop them. The potential importance of these deposits to the Nation's future economic growth and security requires that these problems be wisely resolved, and precludes hasty policy decisions that might have unfortunate consequences in the long term.

The part oil shale deposits may play in the energy field, their salient features and legal status, the state of their technology, and the technical and economic problems their development presents to the Department are summarized in the following pages. Compilations entitled "Background data for oil shale policy," "Summary of suggestions from the public for oil shale program," and "Bibliography of Bureau of Mines publications on oil shale and shale oil" provide additional background information.

Trends in energy consumption

To understand the role shale oil may play in supplying energy for future needs, it is desirable to examine briefly current trends in domestic and world consumption of energy. Oil from shale, of course, would directly supplement or replace crude oil in nearly all its uses. In evaluating the need for development of shale oil, however, it is necessary to consider other sources of energy also, partly because all fuels are interchangeable in many of their uses, and partly because liquid hydrocarbons can be produced synthetically from most of the organic fuels. And, because of the low cost at which some of the mineral fuels may be transported, it is also necessary to consider world sources as well as domestic ones. Accordingly, current trends in United States and world consumption of energy resources from all sources are summarized in tables 1 and 2 and figures 1 and 2.

Three important conclusions may be drawn from the current trends in energy consumption:

1. Total consumption of energy is increasing steadily in the United States and the world as a whole. In the United States, energy consumption is expected to increase at the rate of about 3 percent per year to the end of the century; if economic development proceeds as we hope, the rate of increase in many other countries may be even greater.
2. The proportion of each of the fuels in our energy mix has changed substantially over the years. Only 20 years ago, for example, about 50 percent of our energy came from coal and only about 12 percent came from natural gas; coal now supplies only about 22 percent of our needs but natural gas and natural gas liquids furnish about 33 percent. These shifts in the part individual fuels contribute to the energy mix partly derive from consumer preference, but they result mainly from changes in the competitive position of the various forms of energy arising from technological advances. Exhaustion of energy resources of various kinds may cause changes in the composition of the energy mix in the future, but it is not a factor in those that have taken place to date.
3. The United States has shifted from a net exporter of petroleum to a net importer, and now obtains about 20 percent of its petroleum products from other countries. This also is a function of cost rather than basic availability, and reflects the surplus of low-cost oil on the world market. It does not result from a shortage of petroleum in the United States, but it does indicate that it is becoming difficult to produce petro-

> leum from present sources in the United States as cheaply as it can be obtained from some of the previously unexploited sources elsewhere.

The exponential rate of increase in energy consumption creates enormous future demands, and will result in a cumulative consumption far greater than would be expected from present rates. For example, we are now using about 7 billion barrels of oil equivalent a year but by the year 2000 we probably will be using about 35 billion barrels of oil equivalent. Our previous consumption of all forms of energy totals about 235 billion barrels of oil equivalent but by the year 2000 we will have used an additional 470 billion barrels--twice the amount used in all our previous history.

TABLE 1

Estimated total energy consumption in the United States 1/

(Million barrels daily of crude oil equivalent)

	ACTUAL							FORECAST			
	1930	1935	1940	1945	1950	1955	1960	1965	1970	1975	1980
Hydro	0.4	0.4	0.4	0.7	0.8	0.7	0.9	1.0	1.1	1.2	1.2
Coal	6.4	5.0	5.9	7.6	6.1	5.5	4.9	5.4	6.6	8.4	10.5
Oil	2.8	2.7	3.6	4.8	6.4	8.3	9.4	10.7	12.0	13.4	14.9
Natural Gas	0.9	0.9	1.3	1.9	2.9	4.3	6.0	7.2	8.5	9.8	11.3
Nuclear Energy	-	-	-	-	-	-	-	-	0.2	0.4	0.9
TOTAL	10.5	9.0	11.2	15.0	16.2	18.8	21.2	24.3	28.4	33.2	38.8

1/ Based upon Table 24 of the publication *Supplies, Costs and Uses of the Fossil Fuels*, U.S. Department of the Interior - Energy Policy Staff - February 1963.

Office of Oil and Gas.
July 1, 1964

TABLE 2

Estimated world consumption of primary commercial energy
(Million barrels daily of crude oil equivalent)

	ACTUAL					FORECAST 1/			
	1929	1937	1950	1955	1960	1965	1970	1975	1980
Hydro	1.5	1.9	3.1	2.8	4.2	4.7	5.2	5.7	6.1
Coal	21.6	21.4	24.3	27.8	33.8	37.3	39.2	41.1	44.9
Oil 2/	4.3	5.8	10.8	16.0	21.9	31.8	43.6	55.7	62.7
Natural Gas	1.1	1.6	4.2	6.0	9.4	13.2	17.5	24.6	35.4
Nuclear Energy	-	-	-	-	-	-	0.5	0.9	1.9
TOTAL	28.5	30.7	42.4	52.6	69.3	87.0	106.0	128.0	151.0

1/ Preliminary

2/ Includes: Crude Oil, Natural Gas liquids, Shale Oil and Synthetic Oils.

Office of Oil and Gas.
July 1, 1964

FIGURE 1

U.S. ENERGY CONSUMPTION

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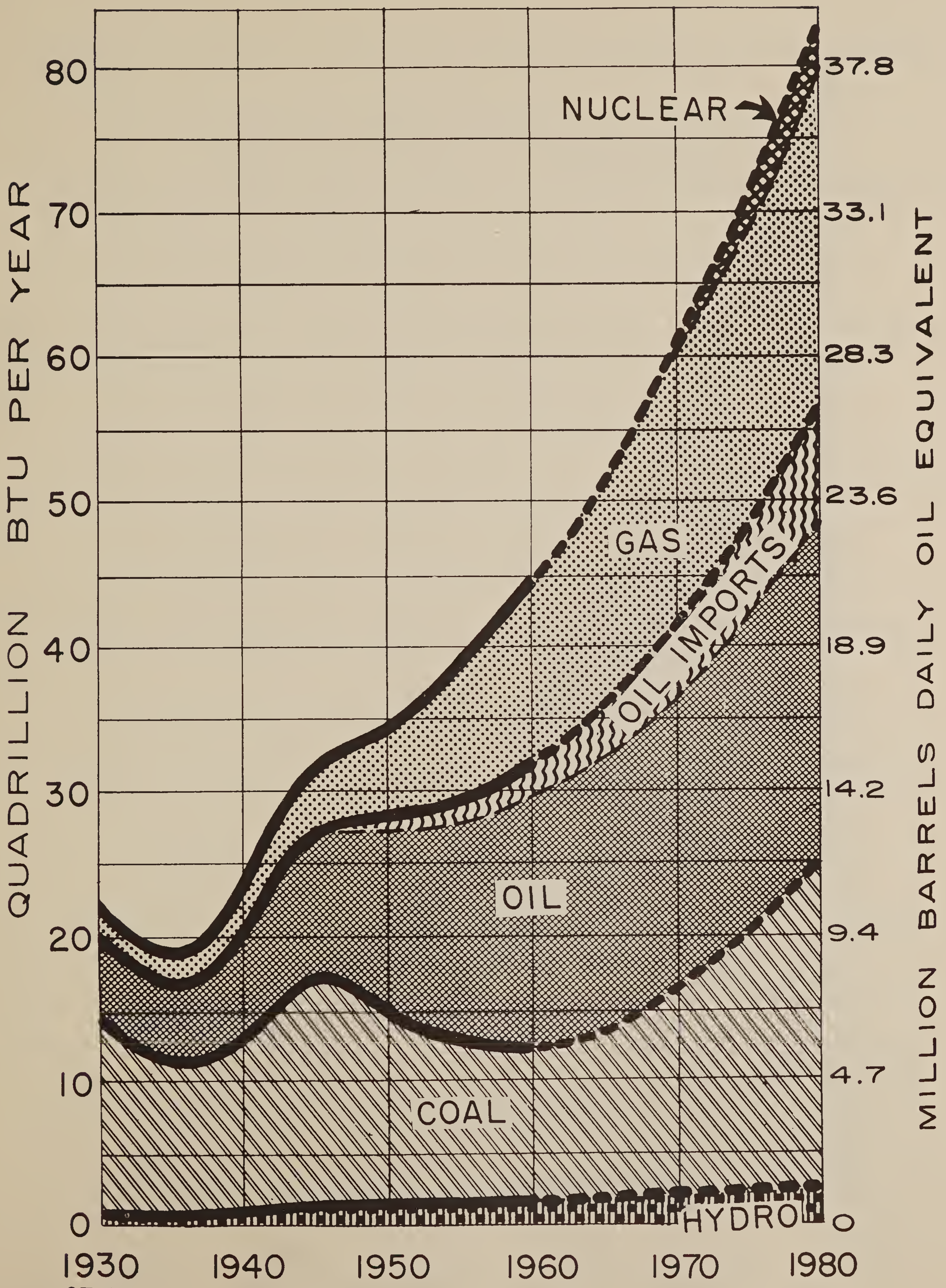
ENERGY POLICY STAFF



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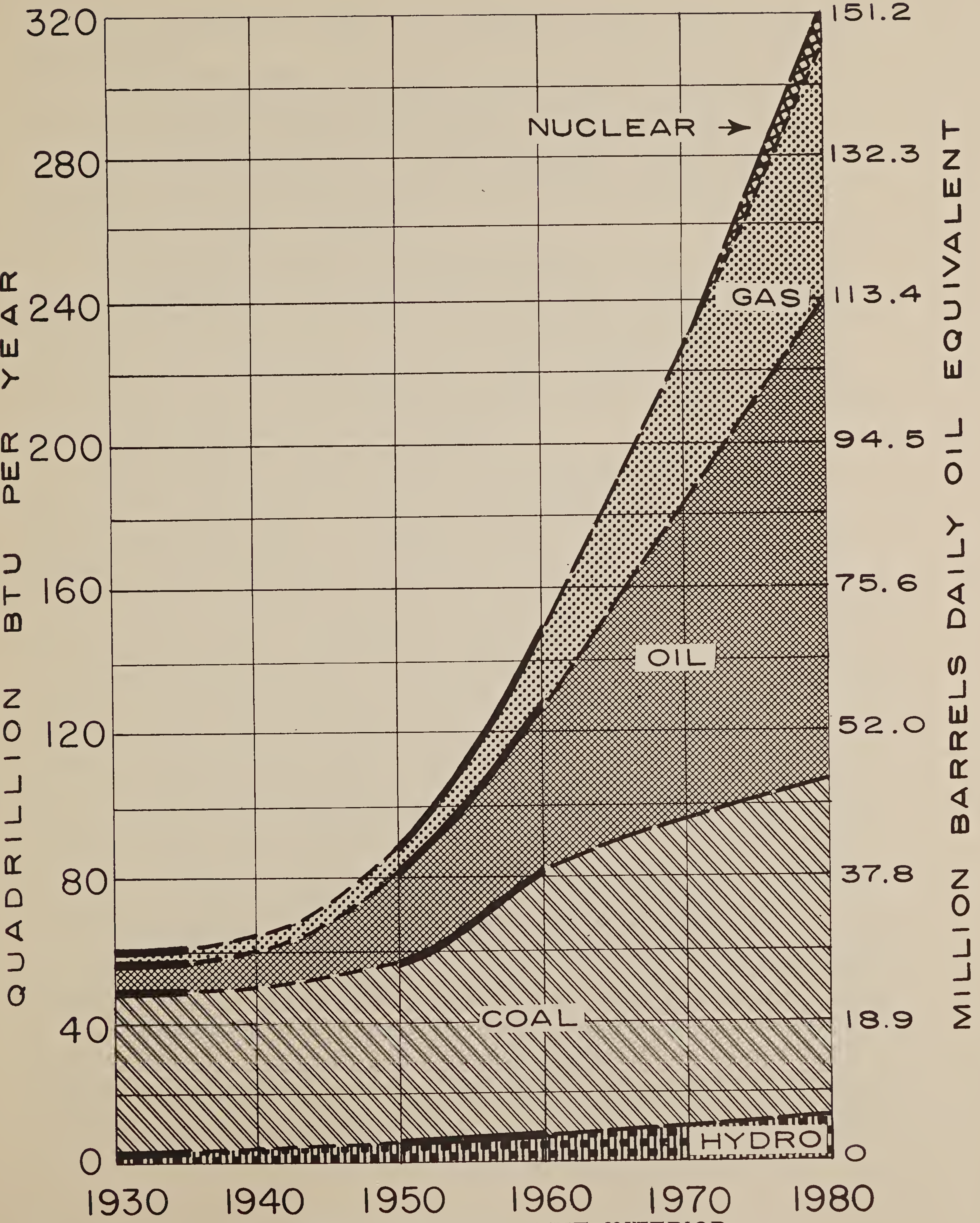
WORLD ENERGY CONSUMPTION



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U. S. DEPARTMENT OF THE INTERIOR
OFFICE OF OIL AND GAS

United States and world resources of energy in fossil and nuclear fuels

Are resources of fossil fuels adequate to meet these accelerating demands?

Current estimates of United States and world resources of fossil and nuclear fuels are summarized in tables 3-8 and figure 3. The estimates include known deposits recoverable under present prices and technology, as well as materials in undiscovered, marginal, and sub-marginal deposits that are not recoverable now but may be recovered at sometime in the future under changed economic or technologic conditions.

The energy in known recoverable reserves of the fossil fuels in the United States totals about 5,500 x 10^{15} Btu, or nearly a trillion barrels of oil equivalent. Nearly 85 percent of the energy in the fossil fuels is in coal, however, and although known reserves of coal are more than adequate to supply our needs through the present century, known reserves of oil and gas fall far short of future needs, and new supplies will have to be developed.

This situation is by no means new--our petroleum industry generally carries a proved reserve (or inventory) equivalent to only a 12- or 13- year supply, and each year it finds and develops new supplies by exploration. As shown in table 3, the Geological Survey estimates that undiscovered resources of petroleum of a character similar to those already developed are about 4 times larger than known recoverable reserves, and known and undiscovered marginal resources add to the potential. It should be emphasized here that marginal and submarginal resources, i.e., resources that for one reason or another cannot be recovered economically now, become recoverable with scientific and technologic advance and may be available in the future at costs not much different than those prevailing now. There are countless examples of advances that have accomplished this in the past, and, in fact, nearly all our current sources of fuels are available only as the result of the scientific and technologic achievements of the present century. The undiscovered and marginal resources shown in table 3, therefore, probably will become available in the future, provided the necessary research and development activities are undertaken.

In addition to undeveloped sources of petroleum, attention should be called also to the bituminous rocks, including the tremendous Canadian tar sands. Like oil shale, they are not a major source of energy now. Considerable progress has been made in developing processes for their extraction, however, and the Alberta Oil and Gas Conservation Board recommended in February that the Alberta government approve the application of the Great Canadian Oil Sands Ltd. for a $191 million project to extract 45,000 barrels of oil per day from tar sands. This

decision followed several years of consideration by the Alberta Oil and Gas Conservation Board. The key element in the decision was to permit tar sands development to approximate 5% of conventional petroleum production in Alberta.

Known United States reserves of oil in bituminous rock are not large, but there are recent reports of large potential resources in Missouri, Oklahoma, and Arkansas. World resources also are probably far larger than are known now, for deposits of this type have not been sought much in the past.

Nuclear sources of energy are enormous. The energy equivalents shown in the tables assume complete burnup and thus depend on the development of the breeder reaction. Nuclear fuels are barely competitive now, but continued technologic advances surely will bring them to a strong position in the energy mix. By the year 2000 they may be expected to supply a substantial part of new demands for electric energy. Their use will probably not diminish total consumption of fossil fuels for sometime, however, and they will not directly replace petroleum in many of its uses.

TABLE 3. United States Resources of Fossil Fuels [1/]
(Energy equivalent in 10^{15} Btu shown in parentheses)

	Known recoverable reserves 2/	Undiscovered recoverable resources	Known marginal resources	Undiscovered marginal resources
Coal (short tons)	220×10^9 (4, 600)	Not estimated	$1,400 \times 10^9$ (29, 000)	$2,600 \times 10^9$ (55, 000)
Petroleum (barrels)	48×10^9 (278)	200×10^9 (1, 160)	40×10^9 (232)	300×10^9 (1, 740)
Natural gas (cu. ft.)	268×10^{12} (295)	1200×10^{12} (1, 320)	Not estimated	850×10^{12} (935)
Natural gas liquids (Barrels)	7×10^9 (32)	30×10^9 (140)	Not estimated	60×10^9 (280)
Oil in bituminous rock (barrels)	1.3×10^9 (8)	Not estimated	Not estimated	10×10^9 (58)
Shale oil (barrels)	50×10^9 (290)	Not estimated	$2,000 \times 10^9$ (11, 600)	$4,000 \times 10^9$ (23, 200)
Total (rounded) energy in fossil fuels (10^{15} Btu)	(5, 500)	(2, 600)	(41, 000)	(81, 000)

Grand (rounded total, all classes (130, 000)

Energy equivalents: 1 short ton of coal = 21×10^6 Btu; 1 barrel petroleum, oil from bituminous rock, or shale oil = 5.8×10^6 Btu; 1 barrel natural gas liquids = 4.62×10^6 Btu; 1 cubic foot natural gas = 1100 Btu; 1 metric ton uranium or thorium = 7.78×10^{13} Btu.

[1/] Provisional estimates compiled by D. C. Duncan and V. E. McKelvey, U. S. Geological Survey. Explanation, definitions, and sources of data are on the following pages.

[2/] As defined here, this category includes measured, indicated, and inferred reserves. Estimates of indicated and inferred reserves of oil, gas, and natural gas liquids are not available; however, the estimates shown are proved (i. e., measured) reserves and therefore not wholly comparable to the estimates shown for the other commodities.

Explanation of resource estimates

Coal. Known recoverable reserves are those in thick coal beds lying at depths less than 1, 000 feet, and assume 50 percent recovery of coal in place. The minimum thickness for beds of bituminous and higher rank coal included in the estimate is 3. 5 feet and that of subbituminous and lower rank coal is 10 feet.

Known marginal resources include coal left in first mining of known recoverable reserves, coal in thin beds at shallow depth, and coal lying at depths between 1, 000 and 3, 000 feet below surface. The estimate refers to coal in place, and includes coal in the measured, indicated, and inferred categories of Averitt, U. S. Geological Survey Bulletin 1136 (with additional data reported by Beikman et al., Washington Division of Mines and Geol. Bulletin 47), less that reported here in the known recoverable class, rounded to two significant figures.

Undiscovered marginal resources refer to coal believed to be in place to depths of 6, 000 feet. No separate estimate has been prepared of undiscovered thick coal at shallow depths. Compiled from estimates by M. R. Campbell, Coal Resources of the World, 1913, less the sum of known reserves and known marginal resources, rounded to two significant figures.

Petroleum. Known recoverable reserves include proved (primary) reserves of American Petroleum Institute (32 billion barrels) plus reserves economically recoverable by secondary recovery methods in practice (16 billion barrels) estimated by Interstate Oil Compact Commission as of January 1, 1962.

Known marginal resources include additional oil in known deposits considered to be physically recoverable by newer secondary recovery methods but possibly at increased costs. The original oil in place in known deposits is estimated by I. O. C. C. to be 346 billion barrels. Production of 68 billion barrels to January 1962, plus primary and secondary reserves of the above estimates total 156 billion barrels or 45 percent of the estimated oil in place. A somewhat larger recovery, as much as 75 or 80 percent of the oil in place, is considered possible eventually with future improvements in recovery techniques; hence the known marginal resources might be as much as 140-160 billion barrels.

Undiscovered recoverable resources include oil in possible extensions of known fields and in undiscovered fields thought to be discoverable under present conditions. Based on unpublished estimates of A. D. Zapp, U. S. Geological Survey.

Undiscovered marginal resources include petroleum accumulations thought to be present in less favorable areas, at greater depths, and in

less productive accumulations than those considered commercially useable under present conditions. The estimate is rounded from one prepared by A. D. Zapp.

Natural Gas. Known recoverable reserves include proved reserves as of January 1, 1962, from American Gas Association and American Petroleum Institute. No estimate has been prepared of known marginal gas resources.

Estimates of undiscovered recoverable resources are based on a ratio of 6,000 feet of gas discovered per barrel of oil. Recent estimates of this ratio range from 6,000 to 8,000 cu. ft. of gas per barrel of oil, and hence the undiscovered recoverable resources of gas may be as high as 1,500 or 1,600 x 10^{12} cu. ft.

Undiscovered marginal resources are Zapp's unpublished estimates of resources not economic now. Because a larger fraction of natural gas in subsurface reservoirs is recoverable than oil under present circumstances, the estimate of submarginal resources of gas is less generous than that for oil. Deep drilling, however, might produce much larger quantities, for experience already indicates that there is an average increase in concentration of natural gas with depth. The estimate does not include possible large sources such as pore space gas in coal and black shale, or synthetic gas from black shale or coal. For example: the Chattanooga shale and its stratigraphic equivalents probably contain about 8 x 10^{15} cu. ft. of gas equivalent if processed by hydrogenolysis. The four trillion tons of coal in the United States may also contain as much as 8 x 10^{15} cu. ft. of entrapped methane gas, some fraction of which might be recoverable in the future. The carbonaceous shales associated with coal might contain an additional 4 x 10^{15} cu. ft. of gas and some marine black shales such as the Chattanooga and equivalents, may contain comparable or larger amounts of such gas in pore space.

Natural gas liquids. Known recoverable reserves are rounded from API-AGA estimates for January 1962 which indicate a ratio of about 25 barrels of liquids economically recoverable per million cubic feet of gas. Undiscovered recoverable resources are based on the same ratio of natural gas to natural-gas-liquids. Undiscovered marginal resources are Zapp's unpublished estimate which assumes more complete recovery and greater quantities of natural-gas-liquids in the deeper gas accumulations.

Oil in bituminous rock. Known recoverable resources include minimal estimates of some deposits for which ready data are at hand; assumed recovery is 50 percent of the oil in place. An estimate of 10 billion barrels from Weeks, 1960, Geotimes, Vol. 5, No. 1, p. 20, is the basis for the figure on undiscovered marginal resources; it includes a number of known deposits that are unappraised.

Shale oil. Known recoverable reserves include oil recoverable from higher grade oil shale in Colorado and Utah in beds 25 feet or more thick, yielding about 30 gallons of oil per ton of rock, and lying at depths less than 1,000 feet below surface. Assumed recovery is 50 percent of the oil content of the shale. Known marginal resources include shale left in first mining of the known recoverable reserves, estimates of the full oil content of similar higher grade deposits at depths greater than 1,000 feet below surface, and estimates of thin and low grade oil shale, with minimum yield of 10 gallons of oil per ton and minimum thickness of 5 feet and to depths as much as 10,000 feet below surface.

Undiscovered marginal resources include a speculative estimate of equivalent oil content of shale yielding 10 gallons or more oil per ton to depths as much as 20,000 feet and assuming an average of 50 percent conversion of their total energy content to oil. A much larger amount of organic rich shale which probably would yield little oil with present technology is known and inferred. For example: shales not included in estimates shown in the table but containing 10 percent or more organic matter, probably contain more than 8.5 trillion tons of organic matter in known and inferred deposits to depths as much as 20,000 feet. Their potential energy content is 170 x 10^{18} Btu or more. Some undetermined fraction of their potential energy may become available by such methods as combustion or by production of synthetic gas or oil using hydrogenolysis, hydrogenation or other methods not yet developed.

TABLE 4

World resources of the fossil fuels

(Energy equivalent in 10^{15} Btu shown in parenthesis)

	Known recoverable reserves	Undiscovered or marginal resources
Coal (short tons) 1/	850×10^9 (18,000)	$15{,}150 \times 10^9$ (320,000)
Petroleum (barrels) 2/	300×10^9 (1,700)	$4{,}000 \times 10^9$ (23,000)
Natural gas (cu. ft.) 3/	$1{,}800 \times 10^{12}$ (2,000)	$19{,}000 \times 10^{12}$ (21,000)
Natural gas liquids (barrels) 4/	45×10^9 (210)	700×10^9 (3,200)
Oil in bituminous rocks (barrels) 5/	40×10^9 (230)	$1{,}060 \times 10^9$ (6,100)
Shale oil (barrels) 6/	150×10^9 (870)	$13{,}600 \times 10^9$ (79,000)
Total (rounded) energy in fossil fuels (10^{15} btu)	(23,000)	(452,000)

Energy equivalents: 1 short ton of coal = 21×10^6 Btu; 1 barrel petroleum, oil from bituminous rock, or shale oil = 5.8×10^6 Btu; 1 barrel natural gas liquids = 4.62×10^6 Btu; 1 cubic foot natural gas = 1,100 Btu.

1/ Known recoverable reserves consist of half of the measured reserves of coal and lignite reported by Parker (op. cit., p. 10), adjusted to make U. S. reserves conform with those shown in table 1, and to incorporate a different approximation of minable reserves in the U. S. S. R. The latter is based on the 1956 estimates quoted by J. A. Hodgkins (Soviet power, energy resources, production and potential; Prentice Hall, 1961) that 2.09 trillion metric tons of coal in the U. S. S. R. lie above a depth of 300 meters; it is assumed that the distribution of these beds by thickness is similar to that in the U. S., so that 30 percent of the total, or 695,000 short tons, is in thick beds, half of which are recoverable.

Undiscovered or marginal resources are those reported by Parker, adjusted to make U. S. reserves conform with those shown in table 1 and to incorporate the 1956 estimate of U. S. S. R. coal and lignite above a depth of 1,800 meters (9.6 trillion tons), less known recoverable reserves.

2/ Recoverable reserves are taken as the U. S. figure from table 1, plus proved reserves in remainder of world (Oil and Gas Jour., v. 60, no. 53, p. 85, 1962). Undiscovered or marginal resources are the undiscovered recoverable, known marginal, and undiscovered marginal reserves for

the U. S. (table 1), plus unpublished estimates of A. D. Zapp for the other areas; the latter are based on an extrapolation of U. S. estimates to the remainder of the world according to area of sedimentary rocks and to the geologic favorability factors derived from Weeks, L. G., 1959, Where will energy come from in 1959?: Petroleum Engineer, v. 31, no. 9, p. A24-31.

3/ There are no available estimates of proved world gas reserves. Hence, known recoverable reserves are estimated on the basis that 6,000 cu. ft. of gas are expectable per barrel of oil. Estimates of undiscovered and marginal resources are unpublished ones of Zapp and allow a somewhat lower gas-oil ratio for marginal resources.

4/ There are no available estimates of proved world reserves of natural gas liquids. Known recoverable reserves are estimated on the basis that natural gas contains about 24 barrels of natural gas liquids per million cubic feet of gas as in the U. S. Estimates of undiscovered and marginal resources are unpublished ones of Zapp and allow a somewhat larger ratio between liquids and gas in marginal resources.

5/ Estimates of known recoverable reserves include only deposits in U. S. and Canada. Canadian reserves of 37.9×10^9 barrels have been calculated by H. L. Berryhill, Jr., from information on extent of deposits now obtainable by open-pit mining methods reported by Oil and Gas Jour., v. 59, July 31, 1961, p. 253, and August 14, 1961, p. 79, and on the assumption that 75 percent of the oil in place is recoverable. Undiscovered and marginal resources are from Weeks (less known reserves), op. cit., 1960.

6/ From unpublished estimate of D. C. Duncan. Recoverable reserves generally are limited to those deposits yielding more than 25 gallons of oil per ton, in zones 25 feet or more thick, and lying less than 1,000 feet below the surface, and assume 50 percent recovery of the oil. In certain foreign areas, however, where an oil shale industry is already established, deposits of the grades and thicknesses currently mined are considered recoverable under certain conditions; in some places deposits containing as little as 12 gallons per ton are mined by open-pit methods. Marginal oil shale deposits are those containing 10 gallons or more per ton in beds lying at depths less than 20,000 feet.

TABLE 5

United States resources of uranium[1]

(Short tons of U. Energy equivalent to 10^{18} Btu shown in parenthesis)[2]

Present cost (dollars per pound of U) 3/	Known deposits	Unappraised and undiscovered resources
5 - 10 4/	142,000 (0.07 - 10)	770,000 (0.38 - 54)
10 - 30 5/	140,000 (0.07 - 10)	500,000 (0.24 - 35)
30 - 100 6/	12,300,000 (6 - 860)	20,000,000 (10 - 1,400)
100 - 500 7/	---	4,000,000,000 (1,960-280,000)

1/ Estimates of uranium in known deposits in the \$5-10 cost range prepared by the AEC; most other estimates prepared by the USGS.

2/ The minimum energy equivalent is that contained in U^{235} and assumes complete burnup. The maximum is the total contained in U^{235} as well as U^{238}. Conversion factor: 1 short ton U = 7×10^{13} Btu.

3/ Based on specific estimates by AEC of mining and processing costs of various types of deposits, assuming present economic and technologic conditions.

4/ Uranium already mined and imported, most of which still exists as uranium, totals 200,000 tons and should be added to known reserves to represent uranium available under present conditions. Known reserves, estimated by AEC, include 135,000 tons in western sandstone deposits averaging about 0.21 percent U, and 7,000 tons in western vein deposits averaging about 0.21 percent U. Undiscovered resources estimated by A. P. Butler, Jr. (unpublished data), include approximately 700,000 tons in sandstone deposits in the Colorado Plateau and adjacent areas and 60,000 tons in vein deposits in the western states.

5/ Known deposits include a) about 23,000 tons recoverable as by-product from the manufacture of triple superphosphate and similar products, taken as 15 percent (the proportion of total phosphate production currently treated by such methods) of the 90,000 tons estimates by V. E. McKelvey (unpublished report, 1952) to occur in beds 3 feet or more thick, and containing more than 30 percent P_2O_5 and lying 1,000 feet below entry level in the western phosphate field and of the 65,000 tons estimated by J. B. Cathcart (unpublished report, 1951) to occur in currently recoverable phosphate concentrates in the Florida field; b) about 8,000 tons in western sandstone deposits and 1,000 tons in vein deposits containing more than 0.1 percent

U but not considered by AEC to be minable at present prices; c) 95,000 tons in sandstone deposits containing 0.04 to 0.1 percent U, estimated by A. P. Butler from the fact that assay data show such materials to be present in amounts equal to about two-thirds of the higher grade ore; and d) 12,000 tons in uranium-bearing pyrochlore in potassic syenite in the Bearpaw Mountains (W. T. Pecora, unpublished data). Unappraised and undiscovered resources include a) 30,000 tons in by-product recovery from the 200,000 tons estimated by J. B. Cathcart (unpublished data) in potential resources in the North Carolina phosphate field; b) 460,000 tons in low-grade western sandstone deposits; and c) 20,000 tons in uranium-bearing pyrochlore deposits.

6/ Known resources include a) about 130,000 tons in the remainder of the known phosphate resources mentioned above (assumed to be recoverable as a principal product in this cost range), b) about 65,000 tons in phosphate concentrates in the Bone Valley formation of Florida; c) about 100,000 tons in aluminum phosphates in the Bone Valley leached zone; d) 6,000,000 tons estimated by Andrew Brown in the Chattanooga shale of Tennessee and adjacent states (averaging about 0.006 percent U); and e) 6,000,000 tons estimated by A. P. Butler in the Conway alkalic granite N. H., to a depth of 1,000 feet. Unappraised resources include a) 600,000 tons in high-grade phosphate rock in the western field lying more than 1,000 feet below entry level; b) 1,300,000 tons in phosphate containing about 0.008 percent U and more than 24 percent P_2O_5 in the western field; c) 200,000 tons estimated by A. P. Butler (from data of G. H. Espenshade) to occur in Northern Florida; d) 1,000,000 tons in phosphate nodules, averaging about 0.005 percent, in the Hawthorne formation of Florida; e) 170,000 tons in the North Carolina phosphates; and f) 16,000,000 tons estimated by V. E. Swanson to occur in the Chattanooga shale in beds containing 0.004 percent or more U.

7/ Includes a) 2 billion tons estimated by V. E. Swanson to occur in the Chattanooga shale and equivalents in central United States in beds averaging about 0.003 percent U; b) 2 billion tons in large granitic bodies (Pikes Peak, Marquette Co., Michigan, Wisconsin, Minnesota, Idaho batholith, California batholith, S. California batholith, N. California batholith, N. Washington batholith, Appalachians, and New England), containing about 4 ppm U above a depth of 1,500 feet (estimated by AEC).

TABLE 6
World uranium reserves [1]
(Energy equivalent to 10^{18} Btu shown in parenthesis[2])

Country	Short tons
United States	142,000 (0.07 - 10)
Canada	236,000 (0.11 - 16)
South Africa	127,000 (0.06 - 9)
France	34,000 (0.02 - 2.4)
Australia	13,700 (0.007 - 0.96)
Sino-Soviet Bloc	110,000 - 400,000 (0.05-0.2; 7.7-28)
Other 3/	21,000 (0.01 - 1.5)
Total (rounded) non-Communist world	575,000 (0.28 - 40)
Total (rounded) world	685,000 - 1,085,000 (0.34-0.53; 48-76)

1/ Known deposits minable at $5-10 per pound; those for the United States, Canada, and South Africa represent material minable at $8 per pound or less. Estimates of reserves in Sino-Soviet Bloc from the McKinney Staff, Report to the Joint Committee on Atomic Energy, Congress of the United States, 1960, v. 4, p. 1613. Estimates on all other countries supplied by R. D. Nininger, U. S. Atomic Energy Commission.

2/ The minimum energy equivalent is that contained in U^{235} and assumes complete burn-up. The maximum is the total contained in U^{235} and U^{238}. Conversion factor: 1 short ton U = 7×10^{13} Btu.

3/ Argentina, Congo, Germany, India, Japan, Mexico, Portugal, and Spain.

TABLE 7

United States resources of thorium 1/

(Short tons. Energy equivalent to 10^{18} Btu shown in parenthesis 2/)

Present cost (dollars per pound Th) 3/	Known deposits	Unappraised and undiscovered resources
5 - 10 4/	100,000 (7)	800,000 (56)
10 - 30 5/	100,000 (7)	1,700,000 (120)
30 - 100 6/	---	30,000,000 (2,100)
100 - 500 7/	---	6,000,000,000 (420,000)

1/ Estimates of thorium in known deposits in the $5-10 cost range prepared by the AEC; most other estimates prepared by the USGS.

2/ Assumes complete recovery. Conversion factor: 1 short ton Th = 7×10^{13} Btu.

3/ Based on specific estimates by AEC of mining and processing costs of various types of deposits, assuming present economic and technological conditions.

4/ Known deposits include about 88,000 tons in vein deposits in the Lemhi Pass area of Idaho (B. J. Sharp, D. L. Hetland, and A. E. Granger, AEC, unpublished data); about 4,000 tons in Idaho and Carolina monazite placers (AEC estimate); and about 16,000 tons in the Goodrich quartzite, Michigan (Vickers, R. C., 1956, Geology and monazite content of the Goodrich Quartzite, Palmer area, Marquette County, Michigan: U. S. Geological Survey Bulletin 1030-F). The estimate of unappraised and undiscovered resources is a speculative one by J. C. Olson, U. S. G. S., that includes 300,000 tons of potential resources in the Lemhi Pass district estimated by Sharp, et al. as well as potential resources in veins in about 20 other promising districts.

5/ Known deposits include 53,000 tons in Carolina placers (Overstreet, W. C., Theobald, P. K., and Whitlow, J. W., 1959, Thorium and uranium resources in monazite placers of the western Piedmont, North and South Carolina; Am. Inst. Mining Eng. Trans., v. 214, p. 709-714), 10,000 tons

in Idaho and Montana placers (Eilertson, D. E., and Lamb, F. D., 1956, A comprehensive report of exploration by the Bureau of Mines for thorium and radioactive black mineral deposits: U. S. Bur. Mines RME-3140, U. S. Atomic Energy Comm. Tech. Inf. Service, Oak Ridge, Tenn.); and 50,000 tons in the Goodrich quartzite. Unappraised and undiscovered resources include 150,000 tons in the Goodrich quartzite; 120,000 tons in a monazite placer off the mouth of the Apalachicola River, Florida (Tanner, W. F., Mullins, A., and Bates, J. D., 1961, Possible masked heavy mineral deposit, Florida Panhandle: Econ. Geol., v. 56, p. 1079-1087); 8,000 tons in Arkansas bauxite (estimated by Olson from data of Adams, J. A. S., and Weaver, C. E., 1958, Thorium-to-uranium ratios as indicators of sedimentary processes: Example of concept of geochemical facies: Am. Assoc. Petroleum Geologists Bull., v. 42, p. 387-430); 14,000 tons in quartz bostonites in Colorado to a depth of 1,000 feet (George Phair, U. S. G. S. unpublished data, 1962); 700,000-1,000,000 tons in hornblende-albite syenite, Wet Mountains, Colo., to a depth of 1,000 feet based on 150-200 ppm ThO_2 (M. R. Brock, U. S. G. S. unpublished data, 1962); 180,000 tons in shonkinite, Mountain Pass, Calif., to a depth of 1,000 feet (J. C. Olson, U. S. G. S. unpublished data, 1962); 4,200 tons in gneiss, Mass., to a depth of 1,000 feet (Johnson, D. H., 1951, Reconnaissance of radioactive rocks of Massachusetts: U. S. Geol. Survey TEI-69, U. S. Atomic Energy Comm. Tech. Inf. Service, Oak Ridge, Tenn.); 10,000 tons in thorium-bearing veins, Wet Mountains, Colo., to a depth of 50 feet (M. R. Brock, U. S. G. S. unpublished data, 1962); 17,000 tons in Cretaceous black sand deposits in the Western states (Dow, V. T., Beatty, J. V., 1961, Reconnaissance of titaniferous sandstone deposits of Utah, Wyoming, New Mexico, and Colorado; U. S. Bur. Mines Rept. Inv. 5860); and a speculative estimate by J. C. Olson of 200,000 tons in thorium-bearing veins containing 0.03-0.3 percent Th to depths of 1,000 feet in the Wet Mountains, Colo., and elsewhere.

6/ Conway granite, N. H., to depth of 1,000 feet. In addition, the Silver Plume granite and Pikes Peak granite, Colo., probably contain 50,000 tons and 100,000, respectively, to depth of 1,000 feet, in rocks with thorium contents of 90 and 50 ppm (George Phair, U. S. G. S. unpublished data).

7/ Large granitic bodies containing 12-30 ppm Th to depth of 1,500 feet, including Pikes Peak granite, Marquette County, Mich., Wisconsin, Minnesota, Idaho batholith, California batholith, S. California batholith, N. California batholith, N. Washington batholith, Appalachians, and New England. Estimated by AEC.

TABLE 8

World thorium reserves, minable at \$10 per pound or less [1]

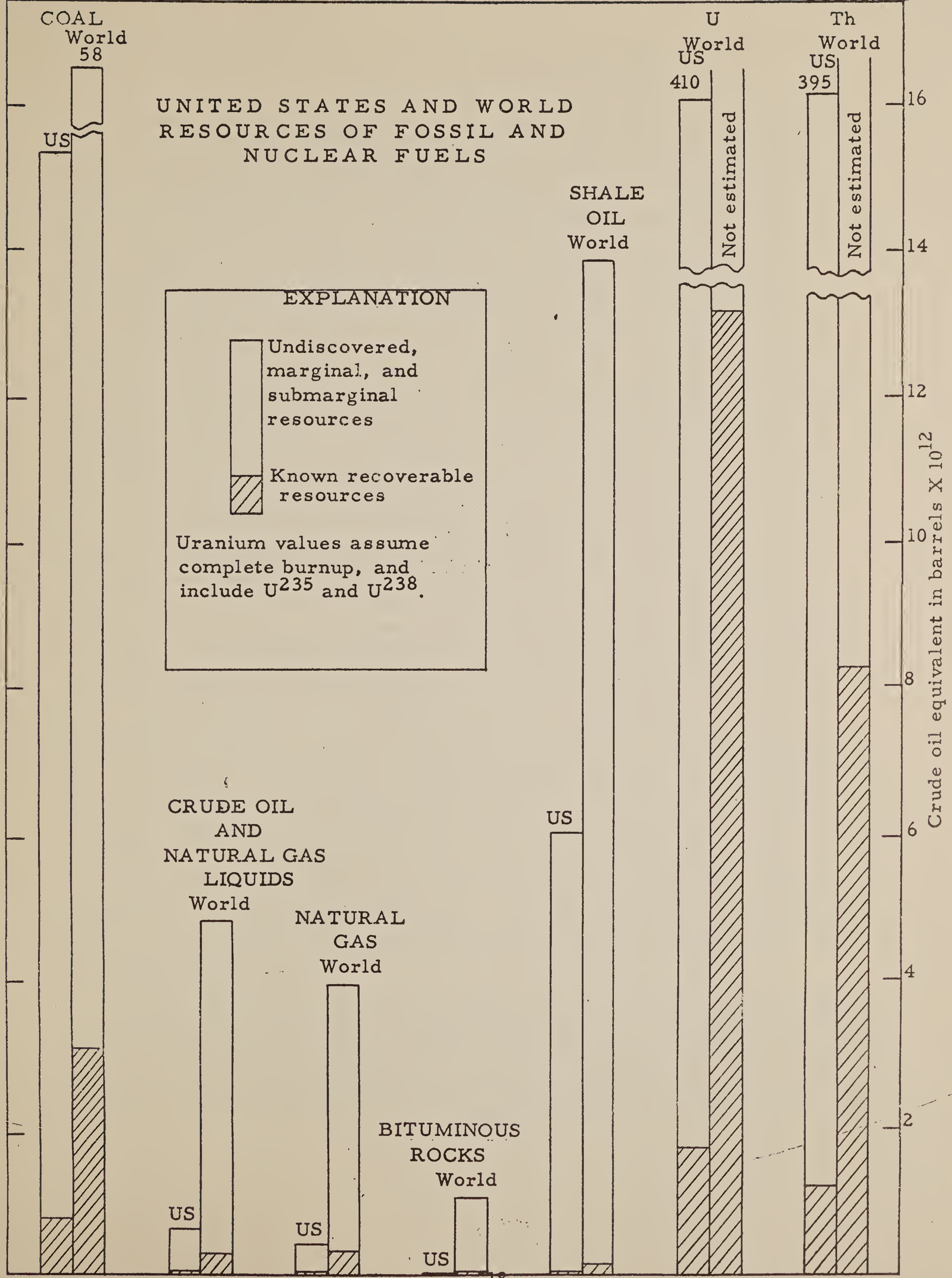
(Energy equivalent to 10^{18} Btu shown in parenthesis)

Area	Short tons
United States	100,000 (7)
Canada	175,000 (12)
Brazil	25,000 (2)
Africa	45,000 (3)
India, Ceylon, Afghanistan, Nepal, Pakistan[2]	220,000 (15)
Sino-Soviet Bloc	90,000 (6)
Australia	45,000 (3)
	700,000 (48)

[1] Estimates for the United States from table 10. Estimate for Australia from Bowie, S. H. U., 1959, The uranium and thorium resources of the Commonwealth; Royal Soc. Arts Jour., v. 107, p. 706; those for other areas from McKinney report, op. cit., p. 1612-1613.

[2] An additional 250,000 tons is possible in the inland placers of Bihar and West Bengal, which have not been thoroughly explored.

FIGURE 3


UNITED STATES AND WORLD RESOURCES OF FOSSIL AND NUCLEAR FUELS
EXPLANATION
Undiscovered, marginal, and submarginal resources
Known recoverable resources
Uranium values assume complete burnup, and include U^{235} and U^{238}.
COAL
World
58
US
CRUDE OIL AND NATURAL GAS LIQUIDS
World
US
NATURAL GAS
World
US
BITUMINOUS ROCKS
World
US
SHALE OIL
World
US
U
World
US
410
Not estimated
Th
World
US
395
Not estimated
Crude oil equivalent in barrels X 10^{12}
2
4
6
8
10
12
14
16

Future place of shale oil in the energy mix

Taking into account resources of fuels from which oil and gas can be made with existing technology (e.g., coal), and additional resources of petroleum that may become available as the result of future exploration and technologic advance, it seems certain that domestic sources of oil would be adequate for our needs through and beyond the present century, even if oil from shale were not available. The question, then, as to whether or not shale oil will enter the energy mix in the immediate future is not one to be answered from the standpoint of basic need but rather from that of competitive cost--the same factor responsible for most other recent changes in the energy mix. Shale oil will have to compete with natural petroleum (including petroleum that now remains trapped in the reservoir rock but that is being recovered to an increasing extent by secondary methods) from both domestic and foreign sources, with oil from tar sands and other bituminous rocks, and with oil made synthetically from coal and carbonaceous shales. The state of the technologic art for recovering oil from these competing sources will be discussed in a later section to this report, but some perspective to the problem may be given by pointing out that: 1) The world petroleum surplus is a temporary one that will be dissipated by expanding world needs. 2) The finding cost of oil shale, tar sand, coal, and secondary petroleum is negligible compared to the finding cost of primary petroleum (for which the finding cost may represent a third of the market price in this country). 3) Extraction of oil from shale and tar sands involves the physically formidable problem of converting a solid to a liquid and removing it from a fine-grained matrix. A moderately high-grade oil shale, for example, contains about 8 percent of solid hydrocarbon distribution in an impermeable matrix from which it probably would not flow at room temperature if it were in liquid form. The petroleum reservoir rock, on the other hand, contains 10 to 30 percent or more fluid hydrocarbon in a pervious matrix from which 20 to 30 percent of the oil will drain naturally. And 4) the capital cost of installations for recovery of oil from shale and tar sands appears to be large, and poses an initial barrier to development and production that is difficult to hurdle.

These advantages and disadvantages are somewhat compensating. Current estimates, however, indicate that the cost of obtaining oil from shale is coming into the competitive range. Perhaps even more significant than specific cost estimates are the actions of major petroleum companies, several of which have requested oil shale leases and outlined

plans for extensive research, development, and production projects. Their actions rather clearly reflect a considered judgment that shale oil will become competitive in the domestic market in the near rather than the distant future.

No matter when shale oil becomes competitive, it will probably enter the market gradually, competing in a limited geographic area with marginal petroleums from other sources. Eventually, however, it will dominate the oil market. As the world's largest concentration of hydrocarbons, the Rocky Mountain oil shales will one day be of key importance to the Nation's economy and security.

Description of ownership status of the Green River oil shales

The oil-shale deposits that are currently of primary interest in the United States are those in the Green River Formation, which extends over large areas of Northwestern Colorado, East Central Utah and Southwestern Wyoming (Figure 4). The shaded areas represent approximately 2,600 square miles of Green River Formation in Colorado, 4,700 square miles in Utah and 9,200 square miles in Wyoming. Although the area in Colorado is smaller than that in either of the other two States, the oil-shale deposits in Colorado are thicker and richer.

According to recent estimates the shale oil potential of the deposits in the three states is about two trillion barrels. The estimated oil potential of the principal oil-shale deposit in the Colorado Piceance Creek Basin includes about 500 billion barrels in shale yielding more than 25 gallons per ton and about 800 billion barrels in shale yielding between 10 and 25 gallons, or a total of 1.3 trillion barrels in combined high and low grade oil shale. The estimates represent the amount of shale oil in place as indicated by computation from assays of sampled sections.

To date, investigations of Utah's oil-shale deposits have not been nearly as comprehensive as those of the Colorado deposits, and the deposits in Wyoming have been explored least of all. Estimates of oil in place in shales assaying 25 gallons per ton and at least 15 feet thick in Utah and Wyoming are 120 billion barrels and 43 billion barrels respectively. In the State of Utah oil shales which have an assay above 15 gallons per ton that are at least 15 feet thick are estimated to represent 320 billion barrels of oil in place. In Wyoming, oil shales in minable beds richer than 10 gallons per ton are currently estimated at 370 billion barrels. The shale oil in place in the combined high and low grade oil shales in the three States comes to the previously stated total of about two trillion barrels.

In Colorado, the principal oil-shale measures occur within a 1,350 square mile area of the Piceance Creek Basin (Figure 5). The areas facing the Colorado River and its tributaries, and to a lesser extent Piceance Creek and other stream beds where the shale outcrops, are privately-owned. However, virtually all of the central portion of the Basin is federally-owned. Although the oil shales in the center of the basin are buried under hundreds of feet of overburden, nearly 2,000 feet of these beds average 25 gallons per ton. Oil-shale measures of

this richness become progressively thinner toward the basin margin. Near the outcrop facing the Colorado River, the beds averaging 25 gallons per ton are less than 100 feet thick.

Of the entire 1,300,000 acres of land in the oil-shale area in Colorado, 582,000 acres (including Naval Reserves) are federally-owned, 380,000 are privately-owned, and 338,000 are lands in unpatented mining claims. Approximately 1,000,000 acres are underlain by oil-shale deposits and the remainder is contiguous non-shale bearing land, principally the areas of stream valleys between oil-shale outcrops. Virtually all of the central portion of the Piceance Creek Basin is federally-owned land. Federal oil shale averaging at least 25 gallons per ton and 15 feet or more thick probably average about 1,000 feet in thickness, where the shale of this grade on privately-owned land probably averages a little over 100 feet.

Of this previously mentioned 1.3 trillion barrels of oil in deposits containing 10 gallons or more of oil in the Piceance Creek Basin the privately-owned oil shale represents about 100 billion barrels of shale oil and the unpatented mining claims about 100 billion barrels. The remaining lands are federally-owned and contain deposits of about 1.1 trillion barrels in place. Based upon a shale grade of 25 gallons per ton the oil potential would be half of these quantities.

FIGURE 4

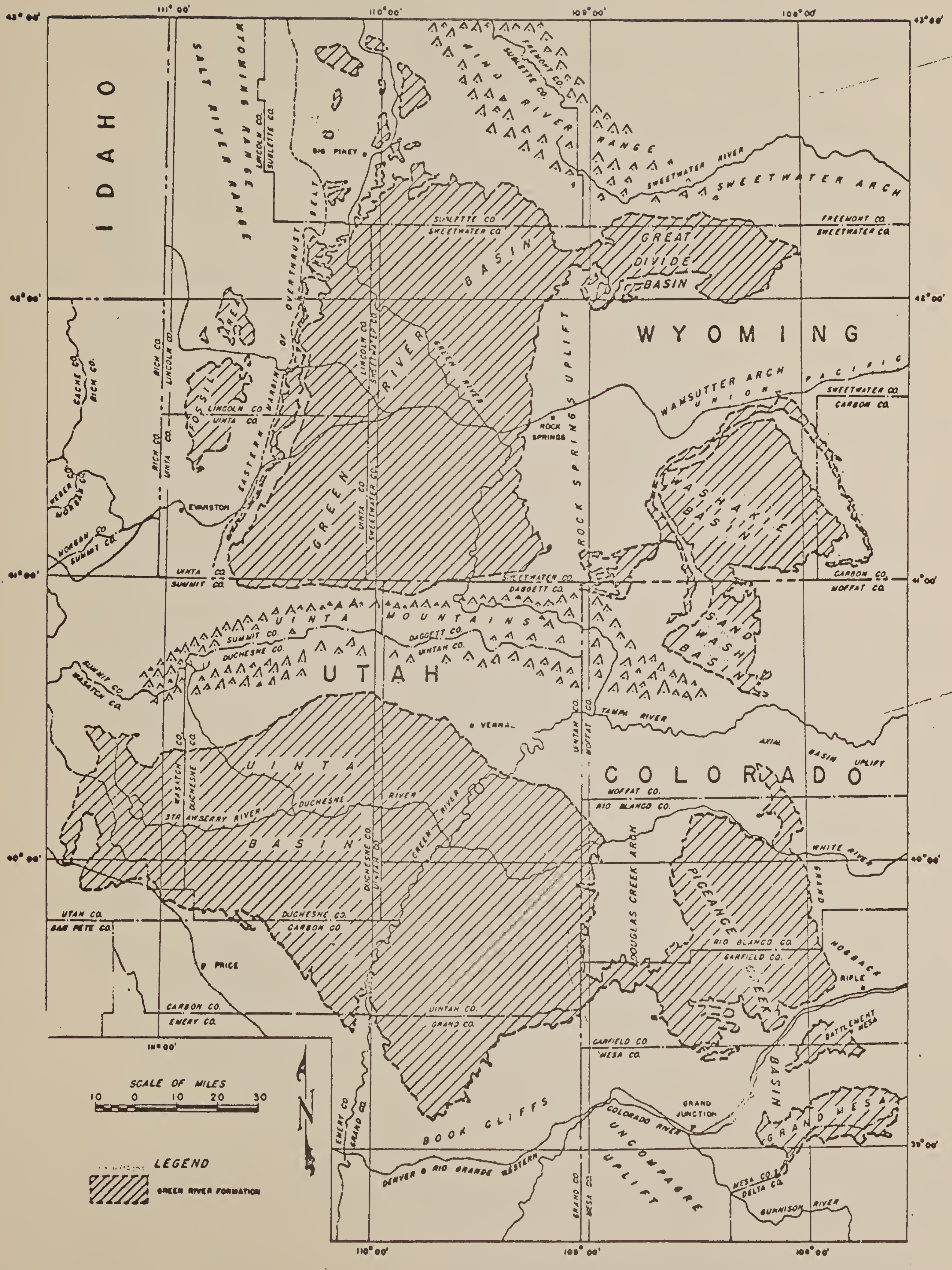


FIGURE 4 Oil-Shale Deposits in Colorado, Utah and Wyoming

FIGURE 5

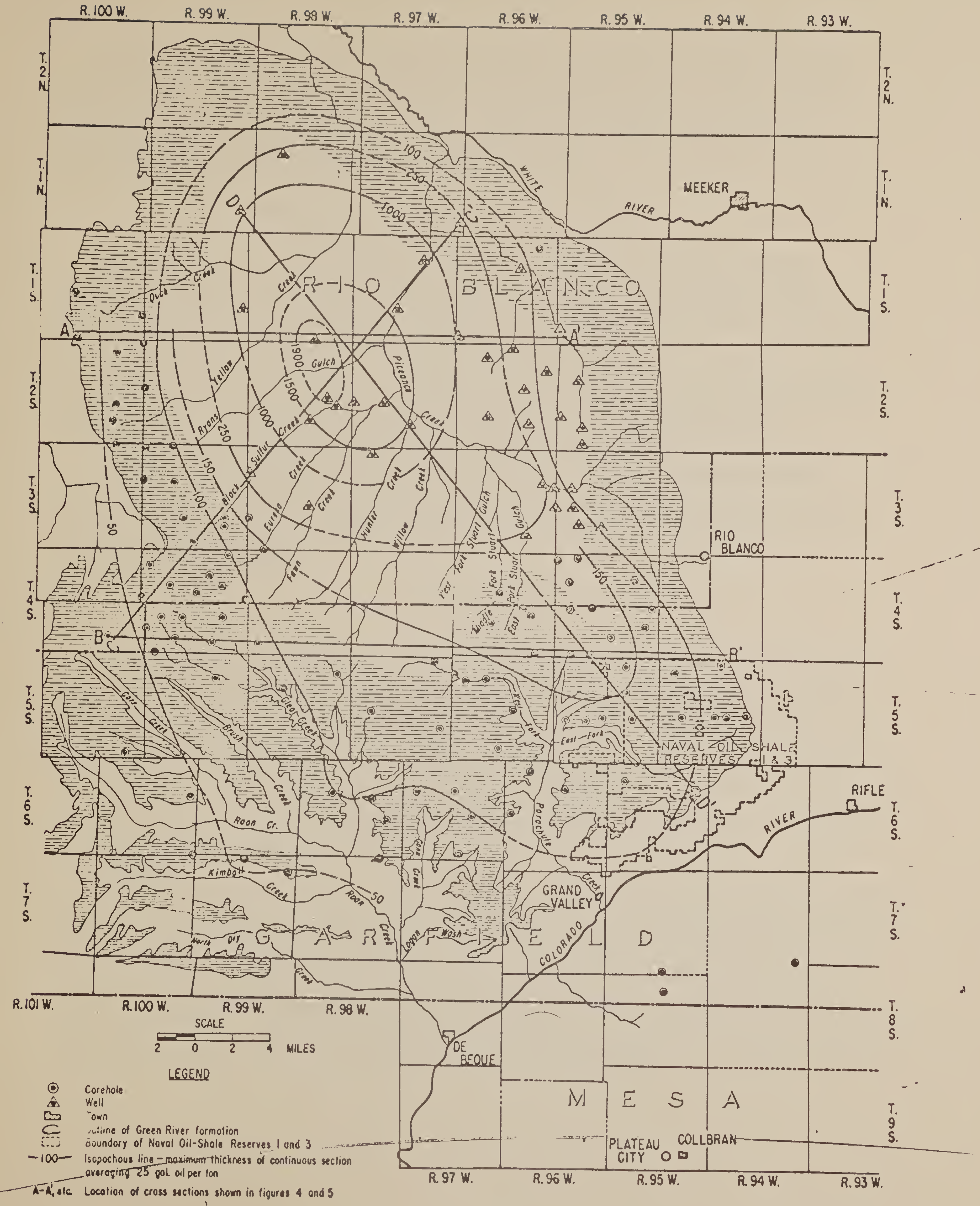


FIGURE 5 - Isopachous Map of 25-Gallon-Per-Ton Oil Shale in Piceance Creek Basin of Northwestern Colorado.

Legal problems in the disposition of oil shale in the public lands

Prior to 1920 oil shale was considered a locatable mineral under the general mining laws. However, in that year it was made subject to disposition only under the provisions of the Mineral Leasing Act of February 25, 1920, 41 Stat. 445, 30 U. S. C. 241, except as to valid existing claims located under prior law.

Withdrawn status of oil shale lands

By Executive Order 5327 of April 5, 1930, the deposits of oil shale and lands containing such deposits owned by the United States were temporarily withdrawn from lease or other disposal for purposes of investigation, examination and classification.

Although the withdrawal order was later modified to permit sodium leasing, and later oil and gas leases of shale lands, it has never been modified or revoked to permit the leasing of oil shale deposits.

Since the withdrawal was made under the authority of the Act of June 25, 1910, 36 Stat. 847, 43 U. S. C. 141, and that authority has been delegated by the President to the Secretary of the Interior (E. O. 10355, May 26, 1952), the Secretary has authority to modify or revoke the withdrawal order.

Acreage limitations

The Mineral Leasing Act authorizes the Secretary to lease deposits of oil shale belonging to the United States and the surface of so much of the public lands containing such deposits, or land adjacent thereto, as may be required for the extraction and reduction of the leased minerals. The Act provides further. . . "that no lease hereunder shall exceed five thousand one hundred and twenty acres of land, ... not more than one lease shall be granted under this section to any one person, association or corporation." This limitation is contained in Section 21 of the Act, as amended.

The Division of Public Lands, Office of the Solicitor, made a careful study of the legislative history of Section 21 at the request of the Solicitor and by memorandum of June 25, 1963, to the Solicitor advised him that, on the basis of such study it has been concluded that the language of Section 21 establishing acreage limitations must be strictly construed. The conclusion reached was that the Secretary is prohibited from granting more than one lease to any one person, association, or corporation and

that such lease can in no event encompass a total of more than 5,120 acres, including such lands as might be leased for the extraction and reduction of the leased minerals and not for their mineral content. The oil shale acreage limitation was made without regard to state or other political boundaries. It should be emphasized that the limitation of 5,120 acres is a maximum and the issuance of a lease for a lesser acreage would preclude the issuance of an additional lease to the same person, association or corporation.

Other provisions of the act

The Act imposes broad discretion in the Secretary to fix royalty rates. It also specifies that the Secretary may, in his discretion, waive the payment of rentals and royalties during the first five years of a lease term to encourage development. This provision would appear to operate as a bar to other methods of encouraging development which have been suggested. The Act speaks in terms of leases only.

Leases may be for indeterminate periods (or fixed periods) to be specified by the Secretary. Royalties are subject to adjustment by the Secretary at the end of twenty years. Rentals are fixed in the sum of 50 cents per acre per annum.

The problem of unpatented mining claims

The Mineral Leasing Act provides that deposits of oil shale shall be subject to leasing as provided therein, except as to valid claims existing on February 25, 1920, and thereafter maintained in compliance with the laws under which initiated and that such claims may be perfected under such laws. (Act of February 25, 1920, Section 37, 41 Stat. 451, 30 U.S.C. 193).

The number of claims located on oil shale lands prior to the effective date of the Leasing Act may well run into the thousands, although many apparently cover the same lands.

The unpatented mining claims present a major administrative problem. The locators or their successors are under no legal compulsion to apply for patent. Therefore, the Department must search out and identify these claims before it can be certain of its authority to lease much of the oil shale lands. In addition, once the claims are identified their validity must be determined.

Early in 1962 the Manager of the Colorado Land Office, Bureau of Land Management, issued a decision rejecting 257 patent applications oil shale placer mining claims located in Garfield and Rio Blanco

Counties, Colorado. All of these claims had been declared null and void in adverse proceedings brought by the Government between 1930 and 1933. The basis for the early adverse proceedings was failure to do assessment work. Subsequently the Supreme Court held that failure to perform annual assessment work was not a ground for cancellation. Ickes v. Virginia Colorado Development Corporation, 295 U. S. 639 (1935).

The Manager of the Colorado Land Office held not that the original cancellations were correct as a matter of law at the time made, but that under principles of finality of administrative action, estoppel by adjudication and res judicata, they cannot now be challenged. This decision was affirmed by the Solicitor of the Department on April 17, 1964. Union Oil Company of California, et al., A-29560. Should the courts ultimately sustain this position the validity of these particular claims will have been finally determined and the validity of others may be determined more expeditiously than otherwise.

Coincidental with the Solicitor's opinion, the Secretary took steps to assure the earliest possible determination of the validity of all other oil shale placer mining claims. On April 17, 1964, he issued instructions to the Director, Bureau of Land Management, to identify all remaining oil shale mining claims in the States of Colorado, Wyoming, and Utah, and begin proceedings in each case in which it appears that the claim may be invalid. The Secretary's memorandum of instruction to the Director set forth certain legal criteria for the determination of validity of such claims. It further provided for the expedition of the administrative processes required for final determination of such validity by instructing that appeals from decisions of the Hearing Examiner or Land Office Manager should continue to be referred directly to the Office of the Secretary for consideration and final decision.

It may be anticipated that at least some of the criteria to be applied in determining the validity of discovery on these old claims will be judicially challenged. Contest actions in which these legal issues are most clearly defined will be initiated first in the expectation that the legal issues will be settled as quickly as possible. Settlement of any legal issues involving the validity of such claims will serve to expedite the entire process of finally determining the validity of all claims.

Technology of hydrocarbon fuels

As a background for considering the impact on fossil-fuel energy supplies and markets of a domestic oil-shale industry, it is advisable to consider other supplemental sources of fossil fuels. These include 1) petroleum and natural gas not now included in proved estimates of reserves but recoverable through new or improved stimulative methods and techniques, 2) bituminous or tar sands, 3) coal, and 4) other bituminous substances, such as gilsonite. Reserves of resources of these materials are shown in table 3.

Petroleum and natural gas

It has been estimated that at least one barrel of oil is left in the ground for every barrel of oil produced after both primary and secondary production. This has presented a challenge to the producer resulting in the development of stimulative production methods designed to convert this resource to a recoverable reserve through supplementing depleted reservoir energy. Early methods included the application of vacuum at well heads, the injection of gas and air, and the injection of water. Waterflooding and reservoir-pressure maintenance by water injection are responsible for the greatest increases in recovery. It was estimated by Torrey that 5,000 water-injection projects in the United States in 1960 accounted for 646 million barrels of the total 2,741 million barrels of oil produced that year, or about 26 percent of the total. However, even after waterflooding had been extended to the economic limit, there still is much oil left in most reservoirs. Consequently, considerable research has been devoted to other methods of stimulating petroleum production that will yield a better recovery. Continuous efforts are made to improve the efficiency of injected water as a medium for displacing oil. Some innovations are the use of carbonated water, and the addition of thickening agents to make the viscosity of the water closer to that of the reservoir oil.

Among the newer, more sophisticated methods of stimulative production are miscible-phase injection and thermal methods. In miscible-phase methods a slug of a fluid is injected that is miscible with both the reservoir oil and with fluids that may be injected behind the slug. Examples are the injection of liquefied petroleum gas followed by natural gas and the injection of gas at pressures high enough to insure complete miscibility. In early laboratory experiments the results promised very high recoveries; however, many field results have been disappointing because of "fingering" of the miscible slugs and consequent inefficient displacement.

Thermal methods include forward and reverse in-situ combustion, hot-fluid injection, and electrical heating. The development of in-situ combustion techniques demonstrates one of the best examples of technology developing before economic practicability is established. It required 10 years of research and development for in-situ combustion or "fire flooding" to be established as an economic recovery method. The total cost considerably exceeded $10 million. Of an estimated 100 projects, perhaps 15 now are considered to be economic successes.

In contrast is the recent application of steam injection to the production of viscous oil, particularly in California fields. Steam injection was proposed as far back as the early 1920's but the technology was not adequate to permit successful application until quite recently. Almost overnight the interest in steam injection has gained momentum, which has been responsible for the unprecedented leasing of land under which there are viscous-oil reservoirs, especially in Missouri, Kansas, and Kentucky. The successful development of steam-injection techniques utilized many fundamental data developed over the 10 years of research on in-situ combustion.

Electrical-heating methods have been used only experimentally and have not been developed to the stage of practical application.

A recent development for displacing oil from viscous-oil reservoirs is the injection of carbon-dioxide gas; however, this still is in the early development stage.

Stimulative methods for gas reservoirs have principally been confined to stimulating the productivity and deliverability of individual wells, rather than entire reservoirs. There are, however, appreciable known deposits of natural gas in reservoirs in the southwestern and Rocky Mountain states that are essentially non-productive because of inadequate permeability. It is possible that techniques may be devised for large-scale stimulation of production from such reservoirs and research is in progress on utilizing the fracturing caused by contained nuclear explosives for that purpose.

The development of successful stimulative methods for petroleum and natural-gas reservoirs can appreciably increase reserves of these fuels but those reserves still will not be adequate to meet the Nation's ultimate needs.

Bituminous sands

There is no adequate definition of the hydrocarbon in the deposits known as tar sands or bituminous sands, as distinguished from sands containing highly viscous oils. One distinguishing feature is that oil in such formations does not flow at ambient atmospheric temperatures even though it often is a highly viscous liquid, as distinguished from kerogen, which is the solid carbonaceous material interspersed in oil shale.

There has been much publicity on the extensive Athabasca (McMurray) tar sands in Alberta, Canada. The most recent estimate by the Alberta Oil and Gas Conservation Board was that those sands contained 450 billion barrels of bitumen and that 60 to 80 per cent would be recovered ultimately. The known deposits of such sands in the United States are neither so great nor so concentrated geographically as those in Alberta. However, the United States deposits are known to be significant and the Department of the Interior and the Interstate Oil Compact Commission are cooperating in a survey of the resources of such sands in the United States.

Considerable laboratory and field research has been conducted on methods of producing oil from the Athabasca tar sands. Several experimental, large-scale industry projects have been underway for some time in Alberta.

Similar but more limited research has been conducted on bituminous-sands deposits in the United States. There is no commercial production however from such deposits in either country. The principal reason for this in Canada has been that the Alberta Oil and Gas Conservation Board has maintained a cautious attitude toward authorizing commercial production from the Athabasca sands. In the United States the lack of development principally has been caused by the lack of an economic incentive. The indications now are that the situation will change in both countries.

The Alberta Oil and Gas Conservation Board has adopted the policy that the production of oil from the Athabasca tar sands cannot exceed 5 percent of the petroleum production in Alberta. Recently the Board authorized Great Canadian Oil Sands, Ltd., to proceed with development of a project designed to produce 31,500 barrels of oil daily on the basis of that percentage. However, this later was increased to 45,000 barrels daily, presumably to permit an economic operation. Development cost is expected to be about $124,000,000 and the start of operations is scheduled for late 1965 or early 1966. Great Canadian

plans to use a strip-mining procedure followed by a hot-water separation process. The oil produced will be transported to Ontario for refining in plants operated there by the Sun Oil Company and Canadian Oil, Ltd., both of which are associated with Great Canadian Oil Sands, Ltd.

Application for approval of an operation considerably larger than that planned by Great Canadian has been made by a four-company combine consisting of Cities Service Athabaska, Ltd., Richfield Oil Corporation, Imperial Oil, Ltd., and Royalite Oil Company, Ltd. This combine has spent about $19,000,000 since 1959 on a pilot development near Mildred Lake, Alberta, and estimates that another $10,000,000 expenditure will be needed for additional engineering to permit advance in industry-scale operation. The processing sequence to be used includes mining the tar sand using a huge "mining wheel" that originally was developed by Krupp for large-scale coal mining operations in the Ruhr Valley, Germany. Oil separation is to be effected by an adaptation of the hot-water extraction process, and viscosity reduction of the resulting oil will be accomplished in a thermal vis-breaking operation. The vis-broken oil then will be pipelined to Edmonton for refining in existing refineries. Overall, the development is expected to cost about $356,000,000 to reach a full-scale operation producing 100,000 barrels of tar-sand oil per day.

A third proposal pending approval is that of the Shell Oil Company of Canada. This company also anticipates an operation to yield 100,000 barrels of oil per day, estimating that the required expenditure will be $260,000,000. Shell's approach differs materially from those of Great Canadian and the Cities Service group, involving an in-situ operation consisting of the following steps: Drilling of one injection well and four producing wells on each four acre "unit" to be produced; injecting an aqueous solution of sodium hydroxide into the tar-sand formation followed by injection of steam at 1,000 psi to effect separation of oil from sand and to emulsify the oil; and producing the emulsified oil and aqueous solution from the four production wells using a "gas-lifting" procedure. The emulsion then will be processed in a dehydration step to yield clean, dry oil to be vis-broken for pipelining to Edmonton and refining in a Shell refinery now operating there. It is estimated that full-scale production will involve simultaneous operation of 1,580 wells with 500 wells to be drilled and a similar number retired from service each year. Assuming application approval, operations are expected to start in 1969 and to continue for about 25 years on the basis of Shell's present land holdings. Payout is estimated in the first eight years of the project.

Can-Amera Oil Sands Development, Ltd., has proposed still another tar-sand project in Alberta, which is estimated to cost about $60,000,000 and to be capable of producing 40,000 barrels of oil per day. Details of the process that will be used by this company are not known except that centrifugal separation of oil from the sand is included in the system. Preceding steps then must include a mining operation followed by a slurrying step of some sort to prepare a relatively fluid mixture that would be amenable to centrifugal separation. Can-Amera proposes to distribute its oil product to existing refineries having excess capacity.

The recent development of successful steam-injection techniques in the United States appears to be stimulating interest in the possibility of commercial recovery of oil from bituminous sands and viscous-oil sands in this country.

Gilsonite

It is ironical that of the non-conventional hydrocarbon deposits in the United States, gilsonite, the one which is most limited in quantity, extent, and significance, is the only one that now is produced commercially. The American Gilsonite Company since 1957 has been mining gilsonite in Utah and refining it in its refinery near Grand Junction, Colorado, to make gasoline and metallurgical-grade coke. The crushed gilsonite is melted, mixed with hot recycle oil, and refined. It is of interest that about 900 tons daily of the crushed solid gilsonite is transported 72 miles in a water slurry by pipeline from the mine to the refinery and that it was in the gilsonite refinery that the only shale oil was refined for commercial marketing in 1961 when Union Oil Co. had 20,000 barrels of shale oil refined there after suspending its experimental mining and retorting operations in Colorado. The refinery has a capacity of about 5,000 barrels daily.

Liquid fuels from coal

A typical coal contains 5 percent perfect hydrogen in the form of hydrocarbons. Doubling of the hydrocarbon hydrogen content is required for conversion of the coal to liquid form.

Two processes were developed and used in Germany for preparing liquid fuels from coal on an industrial scale during World War II. The direct hydrogenation process employed discouragingly severe conditions: pressures of about 10,000 psi and a temperature of about 860°F. An alternative, the synthesis gas method employed relatively milder conditions: Pressures of only about 400 psi and a temperature of about 480°F. Improvements have been made in both processes since the war, especially in the one using synthesis gas. Despite these improvements neither process is competitive at present with the liquid fuels produced from petroleum.

Oil shale

Background:

Commercial production of liquid fuels from oil shales dates back further than is generally recognized, starting in France in 1838. Subsequently, industries flourished at various times in Scotland, Australia, Estonia, Sweden, Spain, Manchuria, South Africa, Germany, and Kwantung (China). Today, industrial operations of appreciable size exist only in Spain, the USSR, and other Communist countries, including Estonia, Manchuria, and Kwantung. In addition, Brazil and Thailand promise to be sites of oil-shale industries in the near future.

The Spanish industry is processing about 3,000 tons per day of oil shale for an oil yield of roughly 2,100 barrels. Underground mining is used and the retorting or oil-producing step is accomplished using multiple banks of retorts of about 12 tons per day capacity each. Production of lubricants and chemicals is stressed.

Little detail is available concerning operations in Communist countries. Iron Curtain oil-shale production in 1963, mostly in Estonia, is estimated at about 17 million tons, which is equivalent roughly to 55,000 barrels of oil per day (the shale is relatively high-grade, approximating 50 gallons per ton for the most part). However, some part of the shale is used to produce gas rather than oil to supply a part of the gas requirements of Leningrad. Also, some undefined part of the shale apparently is being burned directly for power generation.

Concerning oil-shale operations behind the Bamboo Curtain, it is generally thought that operations in Manchuria are the largest in the world today, handling perhaps double the quantity of shale processed in the USSR operations. However, the Manchurian shale is relatively poor in oil, averaging only about 15 gallons per ton so that the daily oil output probably is of the order of 33,000 barrels per day. Operations in Kwantung are relatively new and small. Beyond this, the picture is obscure, except that continuous retorts of about 150 tons per day each are used, as also is true in Manchuria. These retorts probably are somewhat similar to the one developed by the Bureau of Mines, described in more detail later.

An oil-shale industry of significant size has never existed in the United States, although limited amounts of shales in Pennsylvania and New York were processed as early as Revolutionary War days and again during the mid-1800's, principally for the manufacture of kero-

sene. Later, from 1914 to 1927, a small intermittent, commercial operation was conducted in Nevada. Despite the lack of commercial development, interest in oil shale as a source of both liquid and gaseous fuels has continued. This interest has increased markedly since World War II as research and engineering by Government and industry have resulted in technically feasible means for mining shale on a large scale and for converting the shale to finished products equivalent to their petroleum counterparts at almost if not quite competitive cost. Rather conclusive evidence of this is seen in the recent announcement by an industry group (The Oil Shale Corporation, Standard Oil Company of Ohio, and Cleveland-Cliffs Iron Company) of its intention to establish an integrated mining and retorting (oil producing) plant in western Colorado to produce about 45,000 barrels of shale oil per day.

In general, the operational steps involved in producing finished shale-oil products consist of mining and crushing the shale rock, retorting (heating) the crushed product to yield a raw shale oil, and refining the oil to yield marketable fuels, such as gasoline, diesel fuel, and burner fuel oils. An intriguing approach still in the early developmental stage, that of in-situ processing, would eliminate mining, crushing, and retorting as separate steps but would require counterpart operations in the shale beds themselves. Following is a resumé of the status of technologic development of the various operational steps, the principal limitations of an oil-shale industry, and the economics involved.

Mining:

A low-cost underground mining method was developed and demonstrated by the Bureau of Mines at its oil-shale facility near Rifle, Colorado, during the period 1946 to 1956. The method was applied to the Mahogany layer of shale, which is about 73 feet thick at the Rifle location and is exposed on the shale cliff face. A room and pillar pattern of development was used in which mined areas approximately 60 feet square and the full 73 feet high are opened, leaving 60 feet square pillars as roof supports, in a pattern to permit about 75 percent extraction. Sufficient head and side space is provided at all times to permit the use of extremely large equipment in the interest of attaining high output per man-shift, which averaged 150 tons during normal operating tests. Subsequently, essentially the same mining method was adopted and again successfully demonstrated on a large scale by the Union Oil Company during its experimental oil-shale operations some distance west of the Bureau's location.

Current thinking is that single-mine units of about 30,000 tons per day are in the optimum range. Assuming 75 percent extraction, this size mine in 100 feet thick beds would deplete an area of about 1,050 acres in 20 years. Assuming further a shale grade of 25 gallons per ton and 90 percent retorting efficiency, almost 120 million barrels

of oil would be produced. In other terms, a 5,120 acre lease could produce about 625 million barrels of shale oil.

Mining costs using the Bureau's system were estimated in the early 1950's to approximate 30 cents per ton, using rotary drilling techniques. Costs on a dollar basis have risen since then in line with general rises in costs of equipment and labor. However, drilling and blasting techniques also have been improved, so that it is estimated that the mining cost today still should not exceed 45 to 50 cents per ton.

Studies indicate that the room and pillar mining method is adaptable to shales other than those of the Mahogany Zone and to areas far separated from an exposed face by gaining entry to the shale through vertical shafts. Similarly, open-pit mining may be practical in some areas where ratio of overburden to shale is not excessive, including the Piceance Creek area of Colorado where the oil shales are deeply buried but extremely thick. However, comprehensive studies followed by demonstration would be required to assess probable costs and technical aspects. To illustrate what might be in the range of possibility, Utah's large-scale, open-pit mining operations for copper ore are reported to entail costs in the range of 20 to 30 cents per ton at an operational scale of 300,000 tons per day.

Crushing

Except in an in-situ operation, described later, the oil shale from the mining step must be crushed to a size appropriate for retorting. The extent of size reduction that is necessary depends both on the size of pieces resulting from blasting in the mining operations and on the type of retort to be used. Retorting size ranges from about 3 inches in the case of the Bureau's and the Union Oil Company's retorts to as small as 1/4-1/2 inch for The Oil Shale Corporation's retort, all of which are considered in more detail below.

Actual day-to-day oil-shale crushing experience was obtained by the Bureau throughout the period of operations at Rifle involving commercial jaw, gyratory, and roll-type equipment. In addition, the Bureau and several cooperating organizations have conducted crushing tests with various modifications of the equipment available at Rifle and also with impact-type equipment. As a result, it is known that the crushing step holds no critical problem although refinements in techniques are considerably possible. In any case, the cost of crushing is a relatively small factor in the overall cost of producing fuels from oil shale. Based on studies made several years ago, crushing costs were estimated to approximate 15 cents per ton for a size reduction from 60 inch mine-run pieces to 3 inch particles such as would be charged to the Bureau of Mines retort described below.

Retorting

Application of heat to reach a temperature in excess of 900°F. is the only practical means of producing shale oil that is known, and numerous heating processes involving mechanical devices known as retorts, within which to heat oil shale, have been developed. In the oil-production step, the solid organic matter that occurs in oil shale to the extent of about 16 weight percent is converted under the influence of heat to shale oil which is the equivalent of a rather low-grade natural petroleum. The shale oil is black and viscous, contains about 2 percent nitrogen as organic compounds (much higher than a natural petroleum) and is deficient in hydrogen compared to natural petroleum.

Of the many retorting systems that have been investigated, only three are considered to be immediately applicable in large-scale operations--the Bureau's gas-combustion process, the Union Oil Company's process, and The Oil Shale Corporation's (TOSCO) process. Each of these is thermally self-sufficient, heat being supplied by combustion of the carbonaceous residue that is left on oil shale after the oil has been evolved and, in the Bureau's and The Oil Shale Corporation's processes, of part of the gas that is produced. The carbonaceous residue mentioned normally represents about 10 percent of the heating value of the organic material present in the processed shale, or about 230 Btu out of an original 2,300 Btu on the basis of one pound of shale assaying 30 gallons of of oil per ton.

The gas-combustion retort is a vertical, refractory-lined shaft in which crushed shale moves downward as a bed of gravity. Retorting heat, furnished by combustion within the retort vessel of part of the gas produced as well as of the fixed carbon in the shale, is transferred by direct gas-to-solids heat exchange. These features promote high conversion and thermal efficiencies. The process was studied at Rifle in three sizes of pilot plants, the largest being operated at a rate of about 200 tons of shale per day. The retort vessel itself measures 6 feet by 10 feet in cross section and is 37 feet high. Cameron and Jones, Inc., a Denver consulting firm staffed largely by former Bureau employees at Rifle, subsequently adapted the gas-combustion process for use with Brazilian oil shale under a development contract with Petrobras. Successful pilot operations were reported in which considerable improvements were obtained over results achieved by the Bureau at Rifle. In particular, the rate of throughput per unit of cross-sectional area was increased about threefold over that achieved earlier at Rifle.

The Union Oil Company retort also features a vertical shaft design and depends on internal combustion as a source of heat. However, differing

from the Bureau's retort, the vessel is circular in cross section, and enlarges in diameter from bottom to top. Also, the shale is forced upward through the Union retort, the gases and oil vapors flow downward, and only the carbonaceous residue left on the retort shale is burned as fuel. This system was demonstrated in a pilot-model having a nominal capacity of 1,000 tons per day in western Colorado in 1956. (Reportedly, as much as 1,200 tons per day of shale were retorted in this retort which approximates the Bureau's retort in overall size).

The TOSCO process consists principally of a retorting kiln in which finely-crushed oil shale is heated to retorting temperature by heat exchange with hot ceramic balls, heated in turn in another vessel by combustion of the carbonaceous residue left on the retorted shale. The system has been demonstrated in a 24-ton per day pilot model by the Denver Research Institute. Although the pilot demonstration has been at a relatively low rate and process details have not been widely publicized, the TOSCO retort is the heart of the industry development announced recently by the company combine mentioned earlier. For commercial application, The Oil Shale Corporation envisions the retort proper as an 8 feet in diameter by 20 feet long kiln having a throughput capacity of 2,400 tons of shale per day.

Another approach to oil-shale utilization is that of hydrogasification to yield a product similar to natural gas. This possibility is being evaluated principally by the Institute of Gas Technology under contract with the American Gas Association, and, although the economics do not appear particularly attractive at the present stage of development, refinements may very possibly bring gasification into use sometime in the future. The previously mentioned USSR operations that supply part of Leningrad's gas requirements lend support to this possibility.

Refining

Most of the work that has been done on shale-oil refining has been along lines of adaptation of established petroleum-refining processes designed to manufacture a full range of fuels comparable in quality to those in the petroleum family. However, the properties and composition of shale oil differ in several important regards from most crude petroleums, and these differences dictate to some degree both the refining processes and process sequences that are applicable to shale oil. Most important in this regard, shale oil contains a relatively high concentration of nitrogen, which poses problems in regard to deactivation of refining catalysts and tends to cause deterioration of

refined products. In addition, shale oil is relatively viscous and solidifies at a relatively high temperature compared to the normal petroleum crude oil, which aggravates the problem of pipeline transport. However, such well-known processes as vis-breaking and coking have been shown both by the Bureau and industry to offer practical solutions to the viscosity and high pour point problems, and hydrogenation has been shown to be effective in combatting the nitrogen problem, permitting subsequent refining by catalytic means much as are normally practiced in the petroleum refining industry.

In-situ processing

Simply stated, the in-situ process as envisioned for oil shale involves drilling a number of holes into the shale formation, establishing communication between holes by fracturing (for example by well-developed oil-field hydraulic-fracturing procedures or by use of explosives, either conventional or nuclear), igniting the oil shale at selected points in one or more of the drilled holes, and moving the combustion front toward the others by injection of air and gas into the ignition holes. The hot combustion gases, moving through the formation along with excess air and other gas that might be injected, effect retorting at some distance ahead of the combustion zone. The oil and gas produced are swept through the formation to the exit holes for recovery by normal rise or artificial lifting as necessary. As in any retorting process, a carbonaceous residue will be left on the retorted shale and should provide all or at least most of the fuel needed to support the combustion. The potential advantage of the in-situ approach lies in elimination of the mining and crushing steps that would be required in any above-ground retorting approach and possibly in reduction of the capital expense associated with the retorting step itself. A secondary benefit would be avoidance of the problem of spent-shale disposal.

The concept of in-situ retorting is not new, as the procedure has been fairly well developed by the petroleum industry as a means of increasing recovery from certain types of petroleum reservoirs that have been depleted to the point that conventional production methods are ineffective. However, the approach is essentially untried for oil shale, and many technologic problems may be anticipated and must be solved before either the technical or economic feasibility can be assessed. Too, little is known about what percentage of potential oil recovery can be expected or what size of operation might be optimum.

Oil companies known to be actively interested in in-situ processing of oil shale include Sinclair, Humble, Continental, Cities Service, Shell, and Socony Mobil. Sinclair undoubtedly leads the field in actual field work on the process, having operated a pilot venture near Debeque, Colorado, in the early 1950's and now being in the early stages of a new test in the thick shale beds in the Piceance Creek area. At the present site, the high-grade shale beds approximate 1,800 feet in thickness with overburden of about 1,000 feet. Many oil companies, as well as the Bureau of Mines, have conducted laboratory and bench-scale work on in-situ processing with promising results.

Limitations to industry size

The most probable limitations to rate of production of shale oil are those imposed by scarcity of water in the semi-arid oil-shale areas, the availability of suitable sites for mines and associated processing plants, and the problem of spent shale disposal. Of these, the water limitation is generally considered to be most critical. Shale mining and processing in themselves are economical of water; however, it must be anticipated that large municipal and possibly satellite industry requirements will develop as an oil-shale industry develops. In addition, the water problem is aggravated by the extreme seasonal variations that now occur in rate of water flow in the Colorado River and its tributaries, strongly indicating the need for a system of dams and reservoirs to minimize the variations. Water limitations probably also exist for oil-shale operations in Wyoming and Utah.

The problems of site selection and disposal of spent shale are considered subordinate to that of water supply. However, they should not be entirely discounted. The latter in particular may be particularly important in some cases in connection with water pollution problems and certainly could cause disfiguration of the terrain throughout the oil-shale regions if uncontrolled. Possibilities that have been at least casually evaluated for minimizing the spent shale problem include return of the material to mined-out underground workings, revegetation of shale disposal dumps, and use in the manufacture of light-weight concrete. All of these possibilities have promise, although the latter would obviously be a very limited approach in view of the tremendous supplies of spent shale that would stem from any appreciable size industry.

Economics

As far as is known, no comprehensive, completely original studies of the economics of an oil-shale industry have been made since the National Petroleum Council and the Bureau of Mines evaluated the situation

in 1951. The results of these studies were in good agreement, and each showed that a shale-oil industry at that time would be nearly competitive with the petroleum industry. The values calculated in 1951 are now obviously far out of date in view of rises in labor and material costs, known improvements in oil-shale processes, demand for considerably higher return on investment now than then, changes in product-distribution pattern, and other less assessable factors. However, the 1951 studies have been used as a starting point for several subsequent economic estimates in which the changing factors mentioned have been taken into account as accurately as possible without undertaking the tremendous job of a complete new study.

In various escalated estimates taking the above factors into account, capital investment figures ranging from $60,000,000 to $142,000,000 have been derived for an operation in Colorado producing about 50,000 barrels of shale oil per day. Although these apparently are widely divergent, the differences can be largely accounted for by considering the bases of the estimates. In the first case, the figure includes only the necessary investment for mining, crushing, retorting, and minimal processing of the oil for viscosity reduction and upgrading. In the latter case, allowance also is made for development of community facilities ($12,000,000),for construction of a pipeline to California ($21,000,000), and for considerably more oil processing in Colorado ($17,000,000) than in the first case.

For the same two cases, selling prices for crude shale oil of about $2.80 and $3.30 per barrel were developed. Each of these values included all normal operating and capital costs including income taxes at a rate of 50 percent of profit and net return on investment of 12 percent. However, the lower value was based on shale oil at plant site while the higher value allowed for transportation to California. Equalizing the basing point, the values are fairly comparable.

Despite the somewhat vague picture of oil-shale economics that is developed above, the position seems clear that an oil-shale industry is at least marginally competitive with the petroleum industry today. This contention gains support from the fact that The Oil Shale Corporation, in conjunction with the Standard Oil Company of Ohio and Cleveland-Cliffs Iron Company, is actually starting its proposed operations. Too, it is safe to predict that technologic improvements as the result of plant experience will improve the economic picture as operations progress, regardless of which particular processing approach is used.

Security, economic, legal and conservation problems

The fundamental purpose of the Department of the Interior in its administration of oil shale on the public domain is to develop and implement those policies that will be most beneficial to the Nation's long-term economic growth that will contribute most to the national security, and that will permit the wisest use of the land, mineral, and water resources. As indicated at the outset, the Rocky Mountain oil shale deposits pose legal, conservation, and economic problems of major dimensions. Several of these have been mentioned in the previous description, but it is useful to summarize here those that must be considered in devising a policy governing shale oil development.

The most critical problems are those concerning the relation of the rate and extent of the Development of the deposits to the National security and economy. At some time in the not too distant future the Rocky Mountain oil shales will take on tremendous strategic importance to the United States and particularly to its allies, who are becoming increasingly dependent on Middle East sources - sources of somewhat uncertain security. In the wholly economic area, the rate and extent of oil shale development will have deep and far reaching effects on domestic industries (including the petroleum industry itself) on the national economy, and on international markets. Early development of oil shale deposits, for example, might help to relieve the burdensome deficit in the balance of payments stemming from our now-substantial oil imports, and yet savings here might be counter-balanced by other direct and indirect costs. Sound answers to the questions of how to maximize the contribution of this enormous concentrated energy source to the national security and economy are crucial to a sound public policy governing their development.

Other problems are subordinate in importance to these but are critical nevertheless. The rate of development, for example, may be complicated if not retarded by questionable ownership of many of the deposits. Numerous unpatented mining claims were filed prior to the leasing law. Information is lacking on the validity of claims on a large part of the acreage within the 1,100,000-acre withdrawal except for claims against which no reservation was made by the government when they were patented.

The tendency for private industry to acquire natural resources for speculative or protective purposes far in advance of concrete plans to develop them, could also retard development and perhaps add substantially to its cost. The extremely high capital cost of entry into oil shale development and production narrows the range of the organi-

zations able to participate and also could inhibit or retard development. It should be noted that current estimates for minimum economic scale shale oil recovery plants are in the range of $60 to 100 million. Problems of tax depletion allowances remain to be clarified but will bear heavily on the economies of the shale oil industry.

Water--essential for shale oil refining, for the communities that would support the oil shale industry and for many other existing or potential enterprises--is in short supply. Its availability may prove to be a limiting factor in the extent of development and the rate of production.

The great variation in the thickness and oil content of the shale raises difficult policy questions. Whereas oil shale-bearing rocks in the central Rocky Mountain region underlie a total area of about 16,000 square miles, an area in the heart of the Piceance Basin of 350 square miles contains about 600 billion barrels, or nearly half of the oil in the deposits containing more than 10 gallons per ton in the entire field. In some parts of this area, the shale beneath an acre of ground contains 2,500,000 million barrels of oil--1.6 billion barrels per square mile. A standard 5,120 acre tract covering deposits of this nature would contain oil equivalent to 40% of the measured petroleum reserves of the United States. Thus, consideration must be given to richness of deposits as well as to area.

Problems in the realm of conservation are among the most difficult from a technical standpoint. Many of the oil shale lands contain additional known or potential resources, the future value of which must be considered. Included are the land surface itself, oil and natural gas, sodium minerals, and ground water. Uncontrolled strip-mining could spoil the land surface for other uses, yield enormous quantities of waste, and create problems in existing gas fields. In situ mining could adversely affect the extraction of other minerals, and caving from underground mining could affect the surface and impair recovery of sodium salts that in some places lie above the oil shale deposits.

The great thickness of some of the deposits and the interbedding of high-grade and low-grade deposits will make them difficult to mine underground in a way that will yield full recovery. There is already a tendency, fully justified in starting a marginal enterprise, to focus mining plans on high-grade seams the extraction of which might jeopardize recovery of associated lower grade deposits. Adequate solutions to these and related problems must form the base of Federal policies governing the development of this priceless resource.